BC HYDRO
SECOND QUARTER REPORT
FISCAL 2013

BC hydro

FOR GENERATIONS

BRITISH COLUMBIA

This Management's Discussion and Analysis (MD&A) reports on British Columbia Hydro and Power Authority's (BC Hydro or the Company) consolidated results and financial position for the three and six months ended September 30, 2012 (fiscal 2013) and should be read in conjunction with the MD&A presented in the 2012 Annual Report, the 2012 Annual Consolidated Financial Statements of the Company, and the Unaudited Condensed Consolidated Interim Financial Statements and related notes of the Company for the three and six months ended September 30, 2012.

Effective April 1, 2012, the Company changed its financial reporting framework from Canadian generally accepted accounting principles (CGAAP) to the accounting principles of International Financial Reporting Standards (IFRS) except that the Company has continued to apply regulatory accounting in accordance with Financial Accounting Standards Board Accounting Standards Codification 980, *Regulated Operations* (ASC 980) (collectively the "Prescribed Standards"), as prescribed by the Province of British Columbia. All financial information is expressed in Canadian dollars unless otherwise specified, and prior year amounts have been restated to conform to the Prescribed Standards. For more information on the Company's transition to the Prescribed Standards, please see the "Explanation of Transition to the Prescribed Standards" section of this MD&A and Notes 2 and 16 of the Unaudited Condensed Consolidated Interim Financial Statements for the three and six months ended September 30, 2012.

This report contains forward-looking statements, including statements regarding the business and anticipated financial performance of the Company. These statements are subject to a number of risks and uncertainties that may cause actual results to differ from those contemplated in the forward-looking statements.

HIGHLIGHTS

- Net income after regulatory transfers for the three and six months ended September 30, 2012 was $75 million and $128 million, respectively, $12 million higher and $27 million lower, respectively, than the same periods in the prior fiscal year. The increase in the quarter was due primarily to higher domestic revenues and lower expenditures for trade gas purchases, partially offset by lower trade revenues and higher amortization and depreciation expense due to higher assets in service and increased amortization of regulatory accounts. The decrease for the six months was primarily due to higher amortization and depreciation expense and lower trade revenues, partially offset by higher domestic revenues and lower expenditures for trade electricity and gas purchases.
- Usable system inflows for fiscal 2013 are forecast to be 108 per cent of average, comparable to 108 per cent of average in fiscal 2012. At September 30, 2012, the combined system storage in the Company's reservoirs was 110 per cent of average compared to 115 per cent of average at September 30, 2011. As a result of the high inflows, the Company sold a significant volume of surplus energy in the six months ended September 30, 2012, an increase of over 4,000 GWh as compared to surplus energy sales in the first six months of fiscal 2012. The high inflows also resulted in both the Williston and Kinbasket reservoirs spilling substantial volumes of surplus water in the summer of 2012, with the result that usable system inflows for fiscal 2013 will be significantly less than total system inflows.
- Capital expenditures for the three and six months ended September 30, 2012 were $518 million and $953 million, respectively. The Company continues to renew its aging infrastructure and expand its facilities to meet future load growth. Transmission lines and substation replacements and enhancements, as well as the installation of smart meters and related infrastructure, accounted for the majority of the increases in capital expenditures in the current fiscal year.

	For the three months ended September 30			*For the six months ended September 30*		
(in millions)	**2012**	2011	Change	**2012**	2011	Change
Net Income	**$ 75**	$ 63	$ 12	**$ 128**	$ 155	$ (27)
Number of Domestic Customers	**N/A**	N/A	N/A	**1,881,996**	1,860,444	21,552
GWh Sold (Domestic)	**14,855**	12,157	2,698	**28,309**	23,968	4,341
Total Reservoir Storage (GWh)	**N/A**	N/A	N/A	**29,820**	30,420	(600)

(in millions)	As at September 30, 2012	As at March 31, 2012	Change
Total Assets	$ 22,738	$ 21,900	$ 838
Retained Earnings	$ 3,203	$ 3,075	$ 128
Debt to Equity	80 : 20	80 : 20	N/A

CONSOLIDATED RESULTS OF OPERATIONS

These interim statements represent the Company's presentation of its results and financial position under the Prescribed Standards. Under the Prescribed Standards, the Company applies the principles of IFRS plus ASC 980, which differs from IFRS to reflect the rate-regulated environment in which the Company operates. These principles allow for the deferral of costs and recoveries that under IFRS would otherwise be recorded as expenses or income in the current accounting period. The deferred amounts are either recovered or refunded through future rate adjustments.

The transfers to or from regulatory accounts reflected in net income on the condensed consolidated interim statement of comprehensive income include: variances between forecast and actual amounts for certain revenues and costs, including cost of energy, trade income and finance charges; certain amounts incurred in the current period that are deferred for future recovery in rates (such as demand-side management expenditures and liability provisions); interest accrued on regulatory accounts where allowed; and amortization of regulatory accounts into income.

For the three and six months ended September 30, 2012, net transfers to regulatory accounts of $21 million and $78 million, respectively, were primarily due to expenditures on demand-side management programs (DSM), Site C and the Smart Metering and Infrastructure Program (SMI), increases in the provisions for asbestos and polychlorinated biphenyls (PCBs), and the phasing in of the rate impact of the reduction in the amount of overhead eligible for capitalization under IFRS as compared to CGAAP. These increases were partially offset by transfers from the energy deferral accounts primarily resulting from higher than forecast sales of surplus energy and trade income, and lower than forecast finance charges.

Net income after regulatory transfers for the three months ended September 30, 2012 was $75 million, $12 million over the same period in the prior fiscal year. The increase was due primarily to higher domestic revenues resulting from higher average customer rates, higher consumption and higher other energy sales, and to lower expenditures for trade gas purchases as a result of lower gas prices. These increases were partially offset by higher finance charges and higher amortization and depreciation expense due to higher assets in service and higher amortization of regulatory accounts.

For the six months ended September 30, 2012, net income of $128 million was $27 million lower than the same period in the prior fiscal year primarily due to higher amortization and depreciation expense due to higher assets in service and higher amortization of regulatory account balances, and lower trade revenues, partially offset by higher domestic revenues and lower expenditures for trade electricity and gas purchases.

REVENUES

Total revenue for the three months ended September 30, 2012 was $1,128 million, a decrease of $74 million or six per cent compared to the same period in the prior fiscal year. Total revenue for the six months ended September 30, 2012 was $2,186 million, a decrease of $113 million or five per cent compared to the same period in the prior fiscal year. The decrease in both periods was primarily due to lower trade revenues resulting from lower trade electricity and natural gas prices, partially offset by higher domestic revenues resulting primarily from an increase in average customer rates and increased other energy sales.

	(in millions)		*(gigawatt hours)*	
For the three months ended September 30	**2012**	2011	**2012**	2011
Domestic				
Residential	**$ 303**	$ 286	**3,410**	3,405
Light industrial and commercial	**350**	324	**4,589**	4,408
Large industrial	**159**	144	**3,418**	3,374
Other energy sales	**111**	60	**3,438**	970
Total Domestic Revenue Before Regulatory Transfer	**923**	814	**14,855**	12,157
Rate smoothing and load variance regulatory transfer	**(36)**	(56)	**-**	-
Total Domestic	**$ 887**	$ 758	**14,855**	12,157
Trade				
Electricity - Gross	**$ 287**	$ 355	**9,216**	8,429
Less: forward electricity purchases	**(79)**	(75)	**-**	-
Electricity - Net	**208**	280	**-**	-
Gas - Gross	**173**	241	**7,064**	6,061
Less: forward gas purchases	**(140)**	(77)	**-**	-
Gas - Net	**33**	164	**-**	-
Total Trade[1]	**$ 241**	$ 444	**16,280**	14,490
Total Revenues	**$ 1,128**	$ 1,202	**31,135**	26,647

	(in millions)		*(gigawatt hours)*	
For the six months ended September 30	**2012**	2011	**2012**	2011
Domestic				
Residential	**$ 635**	$ 632	**7,106**	7,546
Light industrial and commercial	**694**	638	**8,922**	8,671
Large industrial	**313**	278	**6,761**	6,557
Other energy sales	**170**	113	**5,520**	1,194
Total Domestic Revenue Before Regulatory Transfer	**1,812**	1,661	**28,309**	23,968
Rate smoothing and load variance regulatory transfer	**(31)**	(7)	**-**	-
Total Domestic	**$ 1,781**	$ 1,654	**28,309**	23,968
Trade				
Electricity - Gross	**$ 475**	$ 612	**19,325**	16,667
Less: forward electricity purchases	**(119)**	(146)	**-**	-
Electricity - Net	**356**	466	**-**	-
Gas - Gross	**286**	526	**13,322**	13,107
Less: forward gas purchases	**(237)**	(347)	**-**	-
Gas - Net	**49**	179	**-**	-
Total Trade[1]	**$ 405**	$ 645	**32,647**	29,774
Total Revenues	**$ 2,186**	$ 2,299	**60,956**	53,742

[1] *Trade revenue regulatory transfer is netted with the trade cost of energy transfer to reflect a trade margin transfer.*

DOMESTIC REVENUES

Total domestic revenues after regulatory transfers for the three months ended September 30, 2012 were $887 million, an increase of $129 million over the comparable period in the prior fiscal year. Total domestic revenues after regulatory transfers for the six months ended September 30, 2012 were $1,781 million, an increase of $127 million over the comparable period in the prior fiscal year.

Domestic revenues after regulatory account transfers were higher in the three months and six months ended September 30, 2012 due mainly to higher average customer rates, increased consumption by light industrial and commercial and large industrial customer classes, and higher other energy sales. The increase in consumption by light industrial and commercial and large industrial customer classes was driven by increased economic activity particularly in the metal mining sector due to increased production at new and expanded mines, partially offset by a reduction in activity in the pulp and paper sector due to an indefinite shutdown of one pulp mill. A decrease in residential consumption for the six months ended September 30, 2012 was due to warmer weather conditions. Other energy sales volumes increased due to the volume of surplus energy sold into the market as compared to the same period in the prior fiscal year. The significant increase in surplus energy sales volumes was required due to current hydro conditions.

Average customer rates were higher in fiscal 2013, reflecting an average rate increase of 3.91 per cent approved by the British Columbia Utilities Commission (BCUC) for fiscal 2013 and a Deferral Account Rate Rider (DARR) of 5 per cent for fiscal 2013 compared to a DARR of 2.5 per cent in effect in fiscal 2012.

Variances between actual and planned load are deferred to the Non-Heritage Deferral Account (NHDA) and variances between actual and planned other energy sales are deferred to both the Heritage Deferral Account (HDA) and NHDA.

TRADE REVENUES

Powerex, a wholly owned subsidiary of the Company, is a key participant in energy markets across North America, buying and supplying wholesale power, natural gas, ancillary services, financial energy products, and environmental products with an expanding list of trade partners.

The Company's electricity system is interconnected with systems in Alberta and the Western United States, facilitating sales and purchases of electricity outside of British Columbia. Powerex's trade activities help the Company balance its system by being able to import energy to meet domestic demand when there is a supply shortage and exporting energy when there is a supply surplus. Exports are made only after ensuring domestic demand requirements can be met.

Gross trade revenue for the three months ended September 30, 2012 was $460 million, a decrease of $136 million compared to the same period in the prior year due to a decrease in gross electricity revenue of $68 million and a decrease in gross gas revenue of $68 million. The decrease in gross electricity revenue was primarily driven by a 24 per cent decrease in the average electricity sales price over the same period in the prior year, primarily due to lower Pacific Northwest prices as a result of higher hydro and wind generation. The decrease in gross gas revenue was primarily driven by a 37 per cent decrease in the average gas price reflecting overall lower natural gas prices in North America following continued high shale gas production, partly offset by a 17 per cent increase in gas sales volumes. Deducted from gross trade revenues are forward purchases, which increased by a net $67 million.

Gross trade revenue for the six months ended September 30, 2012 was $761 million, a decrease of $377 million compared to the same period in the prior year due to a decrease in gross gas revenue of $240 million and a decrease in gross electricity revenue of $137 million. The decrease in gross gas revenue was primarily driven by a 43 per cent decrease in the average gas price reflecting overall lower natural gas prices in North America following continued high shale gas production. The decrease in gross electricity revenue was primarily driven by a 29 per cent decrease in the average electricity sales price over the same period in the prior year, primarily due to lower Pacific Northwest prices as a result of higher hydro and wind generation. Deducted from gross trade revenues are forward purchases, which decreased by a net $137 million compared with the same period in the prior year, primarily due to a decrease in gas prices as well as lower forward gas purchases. Forward transactions are reported on a net basis in accordance with the Prescribed Standards. Variances between actual and planned trade income are deferred to the Trade Income Deferral Account (TIDA).

OPERATING EXPENSES

For the three months ended September 30, 2012, total operating expenses of $916 million were $93 million lower than in the same period in the prior fiscal year. Total operating expenses for the six months ended September 30, 2012 of $1,790 million were $98 million lower than in the same period in the prior fiscal year. The decreases in both periods were primarily due to lower expenditures on electricity and gas purchases, partially offset by higher amortization and depreciation expense and lower capitalized overhead.

COST OF ENERGY

Energy costs are comprised of electricity and gas purchases for domestic and trade customers, water rentals and transmission and other charges. Energy costs are influenced primarily by the volume of energy consumed by customers, the mix of sources of supply and market prices of energy. The mix of sources of supply is influenced by variables such as the current and forecast market prices of energy, water inflows, reservoir levels, energy demand, and environmental and social impacts.

Total energy costs, after regulatory account transfers, for the three months ended September 30, 2012 were $435 million, $168 million or 28 per cent lower than in the same period in the prior fiscal year. Total energy costs, after regulatory account transfers, for the six months ended September 30, 2012 were $806 million, $221 million or 22 per cent lower than in the same period in the prior fiscal year. The decrease in both periods was primarily due to lower trade energy purchases as a result of lower natural gas purchase volumes and prices.

Energy costs are comprised of the following sources of supply:

	(in millions)		*(gigawatt hours)*		*($ per MWh)*	
For the three months ended September 30	**2012**	2011	**2012**	2011	**2012**[3]	2011[3]
Domestic						
Water rental payments (hydro generation)[1]	**$ 86**	$ 88	**12,986**	11,914	**$ 6.56**	$ 7.35
Purchases from Independent Power Producers	**196**	219	**2,795**	3,259	**70.22**	67.24
Other electricity purchases - Domestic	**-**	-	**4**	1	**-**	-
Gas for thermal generation	**7**	7	**24**	15	**273.95**	457.99
Transmission charges and other expenses	**(10)**	(4)	**24**	22	**-**	-
Allocation (to) from trade energy	**(1)**	(76)	**(65)**	(2,219)	**21.01**	33.97
Total Domestic Cost of Energy Before Regulatory Transfers	**278**	234	**15,768**	12,992	**17.60**	17.98
Domestic cost of energy regulatory transfers	**(17)**	15	**-**	-	**-**	-
Total Domestic	**$ 261**	$ 249	**15,768**	12,992	**$ 16.54**	$ 19.15
Trade						
Electricity - Gross	**$ 165**	$ 149	**5,936**	5,708	**$ 27.80**	$ 26.10
Less: forward electricity purchases[2]	**(79)**	(75)	**-**	-	**-**	-
Electricity - Net	**86**	74	**-**	-	**-**	-
Remarketed gas - Gross	**160**	234	**7,086**	6,424	**22.58**	36.43
Less: forward gas purchases[2]	**(140)**	(77)	**-**	-	**-**	-
Remarketedgas - Net	**20**	157	**-**	-	**-**	-
Transmission charges and other expenses	**56**	56	**-**	-	**-**	-
Allocation from (to) domestic energy	**1**	76	**65**	2,219	**21.01**	33.97
Total Trade Cost of Energy Before Regulatory Transfers	**163**	363	**13,087**	14,351	**18.46**	31.25
Trade net margin regulatory transfer	**11**	(9)	**-**	-	**-**	-
Total Trade	**$ 174**	$ 354	**13,087**	14,351	**$ 19.29**	$ 30.64
Total Energy Costs	**$ 435**	$ 603	**28,855**	27,343	**$ 17.79**	$ 25.18

[1] *Total GWh is net of storage exchange.*

[2] *Other electricity purchases in dollars include purchases for trade activities shown net of derivatives. Gigawatt hours (GWh) and $ per Megawatt hour (MWh) are shown at gross cost.*

[3] *Total cost per MWh includes other electricity purchases at gross cost.*

For the six months ended September 30	(in millions) 2012	2011	(gigawatt hours) 2012	2011	($ per MWh) 2012[3]	2011[3]
Domestic						
Water rental payments (hydro generation)[1]	$ 171	$ 162	24,586	21,692	$ 6.97	$ 7.54
Purchases from Independent Power Producers	383	382	5,589	5,819	68.58	65.67
Other electricity purchases - Domestic	1	11	41	557	19.30	20.46
Gas for thermal generation	14	15	47	44	288.69	337.95
Transmission charges and other expenses	(43)	(1)	49	48	-	-
Allocation (to) from trade energy	2	(84)	22	(2,348)	17.48	33.02
Total Domestic Cost of Energy Before Regulatory Transfers	528	485	30,334	25,812	17.40	18.79
Domestic cost of energy regulatory transfers	(9)	31	-	-	-	-
Total Domestic	$ 519	$ 516	30,334	25,812	$ 17.11	$ 20.00
Trade						
Electricity - Gross	$ 240	$ 287	14,151	13,529	$ 16.96	$ 21.21
Less: forward electricity purchases[2]	(119)	(146)	-	-	-	-
Electricity - Net	121	141	-	-	-	-
Remarketed gas - Gross	278	509	13,446	13,515	20.68	37.66
Less: forward gas purchases[2]	(237)	(347)	-	-	-	-
Remarketed gas - Net	41	162	-	-	-	-
Transmission charges and other expenses	119	108	-	-	-	-
Allocation from (to) domestic energy	(2)	84	(22)	2,348	17.48	33.02
Total Trade Cost of Energy Before Regulatory Transfers	279	495	27,575	29,392	12.39	22.15
Trade net margin regulatory transfer	8	16	-	-	-	-
Total Trade	$ 287	$ 511	27,575	29,392	$ 12.67	$ 22.70
Total Energy Costs	$ 806	$ 1,027	57,909	55,204	$ 15.00	$ 21.44

[1] *Total GWh is net of storage exchange.*

[2] *Other electricity purchases in dollars include purchases for trade activities shown net of derivatives. Gigawatt hours (GWh) and $ per Megawatt hour (MWh) are shown at gross cost.*

[3] *Total cost per MWh includes other electricity purchases at gross cost.*

Domestic Energy Costs

Domestic energy costs before regulatory transfers of $278 million for the three months ended September 30, 2012 were $44 million, or 19 per cent higher than in the same period in the prior year. For the six months ended September 30, 2012 domestic energy costs before regulatory transfers of $528 million were $43 million or 9 per cent higher than in the same period in the prior year. The increase in both periods was the result of increased surplus energy sales which were 2,469 GWh higher for the quarter and 4,327 GWh higher for the six month period than in the same periods in the prior fiscal year as a result of higher water inflows. This was partially offset by lower purchase volumes from Independent Power Producers (IPPs) and reduced energy costs from water transactions related to the operation of Non-Treaty Storage at Mica.

During the quarter, hydro generation was also used to replace lower deliveries from IPPs which were primarily due to dry weather conditions in parts of the province and maintenance work performed on some IPPs. For the six month period, purchase costs from IPPs were higher despite lower volumes primarily due to the reclassification of one Electricity Purchase Agreement (EPA) to a non-capital lease which increased domestic energy costs in the current year.

An agreement with Bonneville Power Administration (BPA) to operate Non-Treaty storage at Mica (effective September 2011), coupled with the renegotiation of the Non-Treaty Storage Agreement (effective April 2012), reduced energy costs by $7 million for the quarter and $47 million for the six month period (included in Transmission charges and other expenses). Under the agreement, when the Company releases water from its portion of non-treaty storage it is entitled to the value of additional energy flowing through the U.S. Federal Columbia River, as determined by the market price of energy at that time. As at September 30, 2012, the Company has released water from its portion of non-treaty storage.

Variances between actual and planned domestic cost of energy are transferred to the HDA and NHDA.

Trade Energy Costs

Gross trade energy costs for the three months ended September 30, 2012 were $325 million, a decrease of $58 million compared to the same period in the prior year primarily due to a $74 million decrease in gross gas purchase costs partly offset by a $16 million increase in gross trade electricity purchases. The decrease in gross gas purchases was primarily due to a 38 per cent decrease in the average gas price, consistent with the decrease in gross gas revenue. Deducted from gross trade energy costs are forward purchases, which increased by a net $67 million compared with the same period in the prior year.

Gross trade energy costs for the six months ended September 30, 2012 were $518 million, a decrease of $278 million compared to the same period in the prior year primarily due to a $231 million decrease in gross gas purchase costs and a $47 million decrease in gross trade electricity purchases. The decrease in gross gas purchases was due to a 45 per cent decrease in the average gas price, consistent with the decrease in gross gas revenue. Trade electricity purchase costs decreased due to a 20 per cent decrease in the average electricity purchase price primarily due to lower Pacific Northwest prices as a result of higher hydro and wind generation. Deducted from gross trade energy costs are forward purchases, which decreased by a net $137 million compared with the same period in the prior year, primarily due to a decrease in gas prices as well as lower forward gas purchases. Forward purchases are netted against forward sales within gross revenue in accordance with the Prescribed Standards. Variances between actual and planned trade income are deferred to the TIDA.

Water Inflows

Usable system inflows for fiscal 2013 are forecast to be 108 per cent of average, with inflows to the Williston Reservoir on the Peace River system at 114 per cent and the Kinbasket Reservoir on the Columbia River system at 108 per cent. Usable system inflows were approximately 108 per cent of average in fiscal 2012. Both Williston and Kinbasket reservoirs spilled substantial volumes of surplus water as a result of the high inflows over the summer months, with the result that usable system inflows for fiscal 2013 will be significantly less than total system inflows.

The Company's reservoirs have been managed such that the combined system storage in the Company's reservoirs at September 30, 2012 was 110 per cent of average (average for 1986 – 2011), with the Williston and Kinbasket reservoirs at 109 per cent and 113 per cent of average, respectively. In comparison, combined system storage at September 30, 2011 was 115 per cent of average.

PERSONNEL EXPENSES

Personnel expenses include labour, benefits and post employment benefits. Personnel costs for the three and six months ended September 30, 2012 of $126 million and $263 million, respectively, were comparable to personnel costs of $127 million and $265 million in the same periods in the prior fiscal year. In both the three and six month periods, lower labour and severance costs were offset by increased expenditures on post employment benefits and fewer expenses eligible for capitalization in the current fiscal year.

MATERIALS AND EXTERNAL SERVICES

Materials and external services include expenditures for operating and maintenance materials and services provided by third parties. Expenditures on materials and external services for the three and six months ended September 30, 2012 of $135 million and $280 million, respectively, were $7 million and $6 million lower, respectively, than in the same periods in the prior fiscal year, primarily the result of reduced maintenance and other operational activities.

CAPITALIZED COSTS

Capitalized costs are direct overhead costs incurred to support capital expenditures and are transferred from operating costs to property, plant and equipment. The Prescribed Standards are different than CGAAP and only allow direct overhead costs to be capitalized to property, plant and equipment, with the effect that under the Prescribed Standards there is a decrease in property, plant and equipment and a corresponding increase in operating costs. The rate impact of this increase in operating costs on transition to the Prescribed Standards is being smoothed over a ten year period through transfers to the IFRS Property, Plant and Equipment regulatory account. Capitalized costs to either property, plant and equipment or the associated regulatory accounts for the three and six months ended September 30, 2012 were $65 million and $127 million, respectively, comparable to capitalized costs of $75 million and $140 million, respectively, in the same periods in the prior fiscal year.

AMORTIZATION AND DEPRECIATION

Amortization and depreciation expense includes the depreciation of property, plant and equipment, intangible assets, and the amortization of certain regulatory assets and liabilities. For the three months ended September 30, 2012, amortization and depreciation expense was $236 million, $69 million or 41 per cent higher than in the same period in the prior fiscal year. For the six months ended September 30, 2012, amortization and depreciation expense was $466 million, $101 million or 28 per cent higher than in the same period in the prior fiscal year. The increases were primarily due to higher assets in service in the current year and higher net regulatory account amortization.

Increased net regulatory account amortization resulted primarily from higher recovery of energy deferral account balances due to the DARR of 5 per cent in effect in fiscal 2013 as compared to the DARR of 2.5 per cent in effect in fiscal 2012. Regulatory account amortization in fiscal 2013 also includes the amortization of regulatory accounts established for the deferral of IFRS transition impacts, including the IFRS Pensions and Other Post Employment Benefits and IFRS Property, Plant and Equipment regulatory accounts. Also contributing to the increase in net regulatory account amortization in the three and six month periods were the cumulative year to date adjustments recognized in the second quarter of fiscal 2012 for the Company's Amended fiscal 2012-2014 Revenue Requirements Application (Amended RRA) filing which reduced amortization expense in that year. These cumulative year to date adjustments included the reduction of DSM regulatory account amortization for a change in the amortization period from 10 to 15 years and the amortization of the fiscal 2012 opening balances of the Total Finance Charges, Taxes and Amortization of Capital Additions regulatory liability accounts.

GRANTS AND TAXES

As a Crown Corporation, the Company is exempt from paying federal and provincial income taxes, but pays local government taxes and grants in lieu to municipalities and regional districts, and school tax to the Province on certain assets. Total grants and taxes for the three and six months ended September 30, 2012 of $49 million and $97 million, respectively, were comparable to the same periods in the prior fiscal year.

OTHER COSTS (RECOVERIES)

Other costs (recoveries) primarily include gains and losses on the disposal of assets and certain cost recoveries classified as operating costs. For the three months ended September 30, 2012, other costs were offset by cost recoveries, comparable to the same period in the prior year. For the six months ended September 30, 2012, other costs net of recoveries of $5 million were $11 million higher than in the same period in the prior fiscal year due to higher losses incurred on asset disposals and retirements and lower cost recoveries in the current period.

FINANCE CHARGES

Finance charges after net regulatory transfers for the three months ended September 30, 2012 of $137 million were $7 million or 5 per cent higher than in the same period in the prior fiscal year. Finance charges after net regulatory transfers for the six months ended September 30, 2012 of $268 million were $12 million or 5 per cent higher than in the same period in the prior fiscal year. The increase in both periods is primarily due to higher than planned volume of debt issues in the current year partially offset by higher capitalized interest during construction and lower planned other recoveries primarily due to lower planned interest rate swap income and net higher planned regulatory charges in the current year compared to the prior year.

REGULATORY ACCOUNT TRANSFERS

The Company has established various regulatory accounts with the approval of the BCUC. Regulatory accounts allow the Company to defer certain types of revenue and cost variances through transfers to and from the accounts which have the effect of adjusting net income. The deferred amounts are then included in customer rates in future periods, subject to approval by the BCUC.

(in millions)	*For the three months ended September 2012*	*For the six months ended September 2012*
Variances between forecast and actual costs		
Energy deferral accounts	$ (41)	$ (46)
Finance charges	(14)	(20)
Other	(7)	(12)
	(62)	(78)
Deferral of costs for future recovery in rates		
Demand Side Management	28	56
Site C	23	38
Smart Metering and Infrastructure	22	41
Environmental Provisions	23	49
First Nations	4	9
IFRS Property, Plant and Equipment	49	98
Other	2	4
	151	295
Rate Smoothing Account	(9)	(18)
Amortization of regulatory accounts	(74)	(148)
Interest on regulatory accounts	15	27
Net change in regulatory accounts	$ 21	$ 78

For the three and six months ended September 30, 2012, net additions after amortization to the Company's regulatory accounts were $21 million and $78 million, respectively. The net asset balance in the regulatory asset and liability accounts as at September 30, 2012 was an asset of $4,113 million compared to an asset of $4,035 million at March 31, 2012.

Additions to the regulatory accounts during the three and six months ended September 30, 2012 included:

- Expenditures on DSM projects, which support energy conservation, on the Site C project and on SMI in the first six months of fiscal 2013.
- Transfers to the Environmental Provisions regulatory account reflect increases required to provisions for asbestos and PCB contamination.
- Transfers to the IFRS Property, Plant and Equipment regulatory account are for smoothing the rate impact of overhead costs eligible for capitalization under CGAAP but not eligible under IFRS as they are not considered directly attributable to the construction of capital assets.

Decreases in the regulatory accounts during the period included:

- Transfers from the energy deferral accounts due to favourable variances between forecast and actual other energy sales due to high water inflows resulting in higher surplus energy sales, favourable variances between forecast and actual domestic load, and higher trade income, partially offset by higher than forecast energy costs.
- Transfers from the finance charges regulatory account due to favourable mark to market adjustments on certain risk management activities and economic hedge activities, lower than planned other finance charges, and lower than planned volume of debt.
- Transfers from the Rate Smoothing regulatory account smooth the rate increases over the three years covered by the Amended RRA. The balance of the Rate Smoothing regulatory account will be fully drawn down by the end of fiscal 2014.

ACCOUNTING CHANGES

EXPLANATION OF TRANSITION TO THE PRESCRIBED STANDARDS

On April 1, 2012, the Company adopted the financial reporting provisions prescribed by the Province pursuant to Section 23.1 of the *Budget Transparency and Accountability Act* (BTAA) and Section 9.1 of the *Financial Administration Act* (FAA). The Company prepared its condensed consolidated interim financial statements for the three and six month periods ended September 30, 2012 in accordance with IFRS, except that in accordance with the aforementioned legislation, it continues to apply regulatory accounting in accordance with the ASC 980. The application of ASC 980 results in the Company recognizing in the statement of financial position the deferral and amortization of certain costs and recoveries that have been approved by the BCUC for inclusion in future customer rates. In accordance with IFRS, such costs and recoveries would otherwise be included in the determination of comprehensive income in the year the amounts are incurred. The comparative periods included in these financial statements have been restated to the Prescribed Standards. The Company's previously issued interim and annual financial statements prior to and including the year ended March 31, 2012 were prepared in accordance with CGAAP.

PAYMENT TO THE PROVINCE

Under a Special Directive from the Province, the Company is required to make an annual payment to the Province (the Payment) on or before June 30 of each year. The Payment is equal to 85 per cent of the Company's net income for the most recently completed fiscal year unless the debt to equity ratio, as defined by the Special Directive, after deducting the Payment, is greater than 80:20. If the Payment would result in a debt to equity ratio exceeding 80:20, then the Payment will be based on the greatest amount that can be paid without causing the debt to equity ratio to exceed 80:20. No Payment has been accrued as at September 30, 2012 for fiscal 2013 as the Company's debt to equity ratio is at the 80:20 cap prior to the calculation of the Payment.

LEGAL PROCEEDINGS

Since 2000, Powerex has been named, along with other energy providers, in lawsuits and U.S. federal regulatory proceedings which seek damages and/or contract rescissions based on allegations that, during part of 2000 and 2001, the California wholesale electricity markets were unlawfully manipulated and energy prices were not just and reasonable. At September 30, 2012, Powerex was owed US $265 million (CDN $261 million) plus interest by the California Power Exchange and the California Independent System Operator related to Powerex's trade activities in California during the period covered by the lawsuits. The Federal Energy Regulatory Commission (FERC) has concluded that because of a dysfunctional energy market in California between October 2000 and June 2001, certain market-wide refunds will have to be paid by energy providers, including Powerex, to various California parties. It is expected that the receivables owed to Powerex will be offset against the market-wide refund amount that Powerex is required to pay.

The Company has elected not to report information regarding provisions as this information could prejudice the Company's position in ongoing litigation.

RATE REGULATION

In the process of regulating and setting rates for BC Hydro, the BCUC must ensure that the rates are sufficient to allow BC Hydro to provide reliable electricity service, meet its financial obligations, comply with government policy and achieve an annual rate of return on deemed equity (ROE). The annual rate of return is equal to the pre-income tax annual rate of return allowed by the BCUC to the most comparable investor-owned energy utility regulated under the *Utilities Commission Act*. This is in accordance with Heritage Special Direction No. HC2. The allowed rate of return for fiscal 2013 is 11.73 per cent, and is lower than the prior year's allowed rate of 14.38 per cent due to changes to the effective tax rate for FortisBC Energy Inc. upon which BC Hydro's rate of return is based and the elimination of the return on equity adder that was in place in fiscal 2012.

Heritage Special Direction No. HC2 defines equity for rate-setting purposes (Deemed Equity) as 30 per cent of BC Hydro's rate base, which is comprised of a working capital allowance, assets in service (excluding leased assets), and DSM expenditures, less contributions in aid of construction and Columbia River Treaty contributions.

DAWSON CREEK/CHETWYND AREA TRANSMISSION UPGRADE PROJECT

On July 11, 2011, the Company filed an application with the BCUC for a Certificate of Public Convenience and Necessity (CPCN) for the Dawson Creek/Chetwynd Area Transmission (DCAT) Upgrade Project. This project proposes to address electricity supply constraints in the southern Peace region of the province and meet significant forecasted load growth in that region attributable to the development of the Montney natural gas field. The project involves the construction of a new substation, a new 230 kV transmission line and the expansion of an existing substation at an estimated cost of approximately $220 million.

On October 10, 2012 the BCUC issued its decision for the DCAT CPCN Application and agreed that the DCAT Upgrade Project as described in the application is needed, but has delayed issuing a CPCN until further First Nations consultation has been undertaken and BC Hydro has provided a report on the consultation activities by early April, 2013. The additional consultation requirement for the DCAT Upgrade Project will result in a delay of the original in-service date of April 2014 by six to twelve months.

JOHN HART GENERATING STATION REPLACEMENT PROJECT

On May 25, 2012, the Company filed an application for a CPCN for the John Hart Generating Station Replacement Project. This project involves replacing the existing three 1.8-kilometre long penstocks with a 2.1-kilometre tunnel through bedrock, constructing a replacement generating station beside the existing station, constructing a replacement water intake at the John Hart spillway dam, and building a new water bypass facility. The projected cost is approximately $1 billion. If approved by the BCUC, the first replacement generating unit is expected to be in service by 2017 with project completion by the end of 2018. On July 27 and September 13, 2012, the Company filed the responses to approximately 1,000 information requests from the BCUC and intervenors. On September 21, 2012, the BCUC determined that a further procedural conference was not required and that the written proceeding would move to the argument phase, to be completed when the Company files its reply argument on November 22, 2012. The Company anticipates that the BCUC will issue its decision by March 2013.

ALBERTA UTILITIES COMMISSION – HEARING ON THE ALBERTA ELECTRIC SYSTEM OPERATOR'S PROPOSED AVAILABLE TRANSFER CAPACITY RULE

On December 5, 2011, the Alberta Electric System Operator (AESO) filed a proposed rule with the Alberta Utilities Commission (AUC) to allocate available transfer capacity (ATC) between the existing BC - Alberta intertie and new interties when the Alberta system is constrained and cannot accommodate the total ATC of all interties. BC Hydro participated in the hearing opposing the rule because of the harm it would cause to the Company and its ratepayers. A decision on the rule is expected to be issued by the AUC in early 2013.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities for the six months ended September 30, 2012 was $348 million, comparable with cash flow provided by operating activities of $355 million in the same period in the prior fiscal year.

The long-term debt balance net of sinking funds at September 30, 2012 was $13.7 billion, compared with $12.8 billion at March 31, 2012. The increase was mainly as a result of net long-term bond issues totaling $1,048 million ($933 million par value). This increase was partially offset by a decrease in revolving borrowings of $105 million.

PROPERTY, PLANT AND EQUIPMENT EXPENDITURES

Property, plant and equipment expenditures were as follows:

	For the three months ended September 30		*For the six months ended September 30*	
(in millions)	**2012**	2011	**2012**	2011
Distribution system improvements and expansion	$ **73**	$ 80	$ **149**	$ 152
Generation replacements and expansion	**113**	120	**204**	225
Transmission lines and substations replacements & expansion	**210**	140	**355**	235
Smart Metering and Infrastructure program	**77**	53	**174**	70
General, including computers, vehicles and building improvements	**45**	39	**71**	104
Total Property, Plant and Equipment Expenditures	$ **518**	$ 432	$ **953**	$ 786

Total property, plant and equipment expenditures presented in this table are different from the expenditures in the Consolidated Interim Statement of Cash Flows due to effect of accruals related to these expenditures.

Generation capital expenditures were $7 million lower in the second quarter and $21 million lower year to date compared with the same periods in the prior year. The decrease for the quarter and year to date is mainly due to decreased spending on the Fort Nelson Resource Smart Upgrade project and the Bridge-River Townsite Redevelopment project in fiscal 2013, as the

projects went in-service in fiscal 2012, offset partially by increased spending on the Ruskin Dam and Powerhouse Upgrade, Mica Unit 5&6 Installation and GMS Unit 1 to 5 Turbine Rehabilitation in fiscal 2013.

Transmission capital expenditures were $70 million higher in the second quarter and $120 million higher year to date compared with the same periods in the prior year. The increase is primarily attributable to increased expenditures on the Northwest Transmission Line (NTL), Interior to Lower Mainland (ILM) project, Burnaby-New Westminster Transmission, Meridian transformer and Long Lake and other new projects added to implementation phase.

SMI capital expenditures were $24 million higher in the second quarter and $104 million higher year to date compared with the same periods in the prior year as the project is well into the implementation phase in fiscal 2013 with the installation of meters, telecom and information technology infrastructure all in progress.

General capital expenditures were $33 million lower year to date compared to the comparable prior year period due to decreased vehicle expenses and passive land acquisition costs.

RISK MANAGEMENT

The Company is exposed to numerous risks, which can be broadly classified as either "Operating" or "Strategic" in nature. Operating risks arise from the construction, ownership, operation and decommissioning of the company's assets. The consequences of operating risks include safety, environmental, financial, reliability and reputational impacts and can range in scale from minor to catastrophic. Significant strategic risks include both long term and short term load/resource balance, exposure to commodity and financial market prices, stakeholder relationships and access to adequate funding. The potential consequences of these risks are similar to those of operating risks and can vary from minor to significant.

The Company strives to manage all the risks it faces on a cost effective basis, taking into account the potential reward to be gained in return for acceptance of the risk. The Company also strives to manage significant risks in conformity with the provisions of the international standard ISO 31000, *Risk Management – Principles and Guidelines*, or in conformity with the provisions of other externally recognized standards appropriate to the risk being managed.

The Board of Directors is accountable for all risks incurred by the Company and its subsidiaries. Authority for risk management is delegated to the Chief Executive Officer. The Chief Risk Officer is charged with the development of the enterprise risk management framework across all of the Company, which provides the basis for consistent application of risk management practices. The Board of Directors and management regularly review and discuss the risk profile of the organization and consider the nature and amount of risk incurred in the pursuit of the organization's objectives.

There were no changes in the significant risks to the Company's business during the six months ended September 30, 2012 from those discussed in the Management Discussion and Analysis presented in the Annual Report for the year ended March 31, 2012, with the exception of the following:

LOAD/ENERGY RESOURCE BALANCE

System inflows, market prices, and domestic load influence cost of energy. The system inflow energy for fiscal 2012 was 8 per cent above average. Fiscal 2013 had unusually high runoff until July, and then very dry conditions from August through mid-October; as a result, the system inflow energy for fiscal 2013 is now forecast to be eight per cent above normal. Net market sales for fiscal 2013 are now forecast to be 6,500 GWh (equivalent to 12 per cent of our domestic load). Several factors constrain the Company's ability to use its stored system energy to meet load throughout the year. These factors include generating unit outages at major plants (forced outages and capital projects) as well as water management constraints which limit generation at the major plants during some periods. Even when the system has annual net energy sales, some electricity purchases are likely required during constrained periods of the year (e.g. late fall, winter, early spring), while electricity sales may be unavoidable during other periods to minimize spill from system reservoirs. The value of these purchases and sales is subject to market price risk.

Electricity demand is generally increasing as B.C.'s population increases. However, this demand can be variable. Demand for the large industrial customers is particularly uncertain due to variability in export markets and world commodity prices, and the potential for major new loads such as Liquefied Natural Gas (LNG). The Company regularly models the projected supply-demand balance of the system over the short term to plan optimum system operations and over the medium term in an effort to cost-effectively meet demand.

ORGANIZATIONAL RISK

The Company's retirement and voluntary attrition is increasing. The Company's attrition reached a six-year low in fiscal 2011. In addition, a more active job market for employees in trades and specialized technical roles is a significant factor in rising voluntary resignations. The Company is completing a strategic workforce plan for fiscal 2014 to fiscal 2020 to assess the potential gaps between long-term labour demand and supply, and propose strategies to close these gaps. This plan is expected to be approved and in place by the start of fiscal 2014.

FUTURE OUTLOOK

The *Budget Transparency and Accountability Act* requires that BC Hydro file a Service Plan each year. BC Hydro's Service Plan filed in February 2012 forecasts net income for fiscal 2013 at $566 million. The Service Plan included a 3.91 per cent interim rate increase for fiscal 2013.

Subsequent to the Service Plan, the Government issued Direction No. 3 to the BCUC which included, among other things, the setting of the interim rate increase in fiscal 2013 of 3.91 per cent as final and lowering the allowed rate of return on deemed equity for fiscal 2013 from 12.75 per cent to 11.73 per cent. This results in a forecast net income of $520 million for fiscal 2013.

The Company's results can fluctuate significantly due to various non-controllable factors such as the level of water inflows, customer load, market prices for electricity and natural gas, weather, temperatures, interest rates and foreign exchange rates. The impact to net income of these non-controllable factors is largely mitigated through the use of regulatory accounts. The updated forecast assumes higher than average water inflows (109 per cent of average) for fiscal 2013, customer load of 51,515 GWh, average market energy prices of CDN $17.70/MWh, short-term interest rates of 1.05 per cent and a U.S. dollar exchange rate of US$0.9839.

The Company filed an updated forecast with the Province in November 2012. The updated net income forecast for fiscal 2013 is $512 million. The significant changes from the Service Plan (adjusted for the BCUC decision on the Amended RRA) for fiscal 2013 include the following, for which the impacts flow through BCUC approved regulatory accounts for future recovery/refund from/to ratepayers and therefore have no impact on net income in fiscal 2013:

- Customer sales load of 51,515 GWh, a reduction of 2,012 GWh from the Service Plan. This decrease is mainly due to a reduction in load in the residential and large industrial and commercial sectors. Residential has decreased mainly due to lower forecast customer growth as a result of lower housing starts. The large industrial and commercial sector has decreased largely as a result of a slower than expected economic recovery especially in the metal mining and pulp and paper sectors.
- A decrease in the forecast cost of energy resulting mainly from the impact of higher water inflows which is at 109 per cent of average. As a result, hydro-generation is forecast to increase and displace higher priced market energy purchases and increase surplus sales. A decrease in the volume of energy supply required due to the decrease in customer load also contributes to the decrease in energy costs.

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF COMPREHENSIVE INCOME

(in millions)	*For the three months ended September 30* 2012	2011	*For the six months ended September 30* 2012	2011
Revenues				
Domestic	$ 887	$ 758	$ 1,781	$ 1,654
Trade	241	444	405	645
	1,128	1,202	2,186	2,299
Expenses				
Operating Expenses (Note 4)	916	1,009	1,790	1,888
Finance Charges (Note 5)	137	130	268	256
Net Income	75	63	128	155
Other Comprehensive Income (Loss):				
Effective portion of changes in fair value of derivatives designated as cash flow hedges	(23)	38	(18)	27
Reclassification to income of gain (loss) on derivatives designated as cash flow hedges	29	(43)	14	(35)
Foreign currency translation gains (losses)	(5)	41	(3)	38
Other Comprehensive Income (Loss)	1	36	(7)	30
Total **Comprehensive Income**	$ 76	$ 99	$ 121	$ 185

See accompanying Notes to the Unaudited Condensed Consolidated Interim Financial Statements.

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF FINANCIAL POSITION

(in millions)	*As at September 30* 2012	*As at March 31* 2012
ASSETS		
Current Assets		
Cash and cash equivalents	$ 178	$ 12
Accounts receivable and accrued revenue	534	595
Inventories (Note 7)	158	142
Prepaid expenses	219	147
Current portion of derivative financial instrument assets	60	140
	1,149	1,036
Non-Current Assets		
Property, plant and equipment (Note 8)	16,619	15,991
Intangible assets (Note 8)	417	412
Regulatory assets (Note 9)	4,408	4,314
Sinking funds	106	105
Derivative financial instrument assets	39	42
	21,589	20,864
	$ 22,738	$ 21,900
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities (Notes 11 and 13)	$ 1,169	$ 1,431
Current portion of long-term debt (Note 10)	3,507	2,896
Current portion of derivative financial instrument liabilities	158	123
	4,834	4,450
Non-Current Liabilities		
Long-term debt (Note 10)	10,339	10,054
Regulatory liabilities (Note 9)	295	279
Derivative financial instrument liabilities, long-term	101	189
Contributions in aid of construction	1,176	1,106
Post employment benefits	1,193	1,182
Other long-term liabilities (Note 13)	1,460	1,421
	14,564	14,231
Shareholder's Equity		
Contributed surplus	60	60
Retained earnings	3,203	3,075
Accumulated other comprehensive income	77	84
	3,340	3,219
	$ 22,738	$ 21,900

Commitments and Contingencies (Note 14)

See accompanying Notes to the Unaudited Condensed Consolidated Interim Financial Statements.

Approved on Behalf of the Board:

Stephen Bellringer
Chairman

Tracey L. McVicar
Chair, Audit & Finance Committee

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CHANGES IN EQUITY

(in millions)	Cumulative Translation Reserve	Unrealized Gains/(Losses) on Cash Flow Hedges	Total Accumulated Other Comprehensive Income	Contributed Surplus	Retained Earnings	Total
Balance, April 1, 2011	$ -	$ 74	$ 74	$ 60	$ 2,747	$ 2,881
Payment to the Province	-	-	-	-	-	-
Comprehensive Income (Loss)	38	(8)	30	-	155	185
Balance, September 30, 2011	$ 38	$ 66	$ 104	$ 60	$ 2,902	$ 3,066
Balance, April 1, 2012	$ 21	$ 63	$ 84	$ 60	$ 3,075	$ 3,219
Payment to the Province	-	-	-	-	-	-
Comprehensive Income (Loss)	(3)	(4)	(7)	-	128	121
Balance, September 30, 2012	$ 18	$ 59	$ 77	$ 60	$ 3,203	$ 3,340

See accompanying Notes to the Unaudited Condensed Consolidated Interim Financial Statements.

UNAUDITED CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CASH FLOWS

(in millions)	*For the six months ended September 30* 2012	2011
Operating Activities		
Net income	$ 128	$ 155
Regulatory account transfers	(205)	(123)
Adjustments for non-cash items:		
Amortization of regulatory accounts (Note 9)	148	58
Amortization and depreciation expense	309	294
Unrealized gains on mark-to-market	(8)	(12)
Interest accrual	310	308
Other items	8	2
	690	682
Changes in:		
Accounts receivable and accrued revenue	61	81
Prepaid expenses	(72)	(60)
Inventories	(17)	(38)
Accounts payable and accrued liabilities	(95)	(86)
Contributions in aid of construction	86	74
	(37)	(29)
Interest paid	(305)	(297)
Interest received	-	(1)
Cash provided by operating activities	348	355
Investing Activities		
Property, plant and equipment and intangible asset expenditures	(885)	(842)
Cash used in investing activities	(885)	(842)
Financing Activities		
Long-term debt issued	1,052	1,048
Receipt of revolving borrowings	2,850	2,287
Repayment of revolving borrowings	(2,956)	(2,387)
Payment to the Province (Note 11)	(230)	(463)
Other items	(13)	(20)
Cash provided by financing activities	703	465
Increase (decrease) in cash and cash equivalents	166	(22)
Cash and cash equivalents, beginning of period	12	27
Cash and cash equivalents, end of period	$ 178	$ 5

See accompanying Notes to the Unaudited Condensed Consolidated Interim Financial Statements.

NOTE 1: REPORTING ENTITY

British Columbia Hydro and Power Authority (BC Hydro) was established in 1962 as a Crown corporation of the Province of British Columbia (the Province) by enactment of the *Hydro and Power Authority Act*. As directed by the *Hydro and Power Authority Act*, BC Hydro's mandate is to generate, manufacture, conserve and supply power. BC Hydro owns and operates electric generation, transmission and distribution facilities in the province of British Columbia.

The condensed consolidated interim financial statements of BC Hydro include the accounts of BC Hydro and its principal wholly-owned operating subsidiaries including Powerex Corp. (Powerex), Powertech Labs Inc., and Columbia Hydro Constructors Ltd., (collectively with BC Hydro, "the Company") including BC Hydro's one third interest in the Waneta Dam and generating facility. All intercompany transactions and balances are eliminated upon consolidation.

The Company accounts for its one third interest in the Waneta Dam and generating facility as a joint operation. The consolidated financial statements includes BC Hydro's proportionate share of the Waneta Dam and generating facility and BC Hydro's liabilities and expenses, including its share of any liabilities and expenses incurred jointly with Teck Metals Ltd. and its revenue from the sale of the output in relation to the Waneta Dam and generating facility.

NOTE 2: BASIS OF PRESENTATION

(a) Basis of Accounting

These condensed consolidated interim financial statements have been prepared in accordance with significant accounting policies that have been established based on the financial reporting provisions prescribed by the Province pursuant to Section 23.1 of the *Budget Transparency and Accountability Act* (BTAA) and Section 9.1 of the *Financial Administration Act* (FAA). In accordance with the directive issued by the Province's Treasury Board, BC Hydro is to prepare its consolidated financial statements in accordance with the accounting principles of International Financial Reporting Standards (IFRS) except that BC Hydro is to continue to apply regulatory accounting in accordance with Financial Accounting Standards Board Accounting Standards Codification 980 (ASC 980), *Regulated Operations* (collectively the "Prescribed Standards"). The application of ASC 980 results in BC Hydro recognizing in the statement of financial position the deferral and amortization of certain costs and recoveries that have been approved by the British Columbia Utilities Commission (BCUC) for inclusion in future customer rates. Such regulatory costs and recoveries would otherwise be included in the determination of comprehensive income in the year the amounts are incurred.

The impact of the application of ASC 980 on these condensed consolidated interim financial statements with respect to BC Hydro's regulatory accounts is described in Note 9. The accounting policies adopted under the Prescribed Standards have been applied consistently to all periods presented in these financial statements and by all subsidiaries of BC Hydro.

These condensed consolidated interim statements have been prepared by management in accordance with the principles of IAS 34, *Interim Financial Reporting* and IFRS 1, *First Time Adoption of IFRS* and were prepared using the same accounting policies as described in the Company's interim consolidated financial statements for the three months ended June 30, 2012. Accordingly, certain disclosures normally included in annual financial statements have been omitted or condensed. In prior years, these financial statements were prepared in compliance with Canadian Generally Accepted Accounting Principles (CGAAP). In preparing these interim statements, management has amended certain accounting methods previously applied in the CGAAP consolidated financial statements to comply with the Prescribed Standards. The comparative figures for the prior year were restated to reflect these amendments. An explanation of how the transition to the Prescribed Standards has affected the reported financial position, financial performance and cash flows of BC Hydro is also provided in Note 16.

These condensed consolidated interim financial statements were approved by the Board of Directors on November 8, 2012.

(b) Basis of Measurement

The consolidated financial statements have been prepared on the historical cost basis except for financial instruments that are accounted for at fair value through profit and loss (temporary investments, designated long-term debt and derivative financial instruments) and available for sale financial assets (U.S. sinking funds).

(c) Functional and Presentation Currency

The functional currency of BC Hydro and all of its subsidiaries, except for Powerex, is the Canadian dollar. Powerex's functional currency is the U.S. dollar. These consolidated financial statements are presented in Canadian dollars and financial information has been rounded to the nearest million unless otherwise stated.

(d) Key Assumptions and Significant Judgements

The preparation of financial statements in conformity with the Prescribed Standards requires management to make judgements, estimates and assumptions in respect of the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from those judgements, estimates, and assumptions.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. There have been no changes in key assumptions and significant judgements from those disclosed as of June 30, 2012.

NOTE 3: SIGNIFICANT ACCOUNTING POLICIES

The significant accounting policies that have been used in the preparation of these condensed consolidated interim financial statements are summarized in the Company's first quarter financial statements for the three months ended June 30, 2012.

NOTE 4: OPERATING EXPENSES

	For the three months ended September 30		*For the six months ended September 30*	
(in millions)	2012	2011	2012	2011
Electricity and gas purchases	$ 303	$ 476	$ 568	$ 799
Water rentals	82	83	156	154
Transmission charges	50	44	82	74
Personnel expenses	126	127	263	265
Materials and external services	135	142	280	286
Amortization and depreciation (Note 6)	236	167	466	365
Grants and taxes	49	45	97	91
Capitalized costs	(65)	(75)	(127)	(140)
Other costs / (recoveries)	-	-	5	(6)
Total	$ 916	$ 1,009	$ 1,790	$ 1,888

NOTE 5: FINANCE CHARGES

	For the three months ended September 30		*For the six months ended September 30*	
(in millions)	**2012**	2011	**2012**	2011
Interest on long-term debt	**$ 156**	$ 154	**$ 313**	$ 304
Interest on finance lease liabilities	**7**	5	**14**	11
Net interest on defined benefit plan obligations	**50**	48	**99**	95
Less: Capitalized interest	**(17)**	(7)	**(35)**	(20)
Total finance costs	**196**	200	**391**	390
Expected return on defined benefit plan assets	**(46)**	(44)	**(92)**	(88)
Other recoveries	**(13)**	(26)	**(31)**	(46)
Total	**$ 137**	$ 130	**$ 268**	$ 256

NOTE 6: AMORTIZATION AND DEPRECIATION

	For the three months ended September 30		*For the six months ended September 30*	
(in millions)	**2012**	2011	**2012**	2011
Depreciation of property, plant and equipment	**$ 139**	$ 113	**$ 279**	$ 240
Amortization of intangible assets	**14**	13	**28**	26
Amortization of regulatory accounts and other	**83**	41	**159**	99
Total	**$ 236**	$ 167	**$ 466**	$ 365

NOTE 7: INVENTORIES

During the three and six month periods ended September 30, 2012, an impairment recovery of $8 million and $16 million (2011 – impairment of $6 million and $7 million, respectively) was recorded in electricity and gas purchases to adjust the cost of natural gas in storage to its net realizable value as a result of increases in market prices. At September 30, 2012, $52 million (2011 - $70 million) of the carrying value of natural gas in storage was valued at net realizable value.

NOTE 8: PROPERTY, PLANT AND EQUIPMENT AND INTANGIBLE ASSETS

Property, plant and equipment and intangible asset expenditures for the three and six months ended September 30, 2012 were $518 million and $953 million, respectively (2011 - $432 million and $786 million, respectively).

As of September 30, 2012, BC Hydro has contractual commitments to spend $1,280 million on major property, plant and equipment projects over the next three years.

NOTE 9: RATE REGULATION

REGULATORY ACCOUNTS

The following regulatory assets and liabilities have been established through rate regulation. For the three and six months ended September 30, 2012, the impact of regulatory accounting has resulted in increases of $21 million and $78 million to net income (three and six months ended September 30, 2011 - $76 million increase and $150 million increase, respectively).

(in millions)	*March 31 2012 CGAAP*	*Transition to Prescribed Standards (Note 16)*	*April 1 2012*	*Addition (Reduction)*	*Amortization*	*Net Change*	*September 30 2012*
Regulatory Assets							
Heritage Deferral Account	$ 244	$ -	$ 244	$ (67)	$ (25)	$ (92)	$ 152
Non-Heritage Deferral Account	367	62	429	51	(38)	13	442
Trade Income Deferral Account	175	30	205	(11)	(17)	(28)	177
Demand-Side Management Programs	646	(8)	638	56	(27)	29	667
First Nation Negotiations, Litigation & Settlement Costs	543	-	543	9	(3)	6	549
Non-Current Pension Cost	55	322	377	(4)	(9)	(13)	364
Site C	181	-	181	43	-	43	224
CIA Amortization Variance	68	-	68	3	-	3	71
Environmental Provisions	234	88	322	49	(3)	46	368
Smart Metering and Infrastructure	92	-	92	44	-	44	136
Finance Charges	6	43	49	(20)	-	(20)	29
IFRS Pension & Other Post Employment Benefits	-	762	762	-	(20)	(20)	742
IFRS Property, Plant and Equipment	-	254	254	98	(2)	96	350
Other Regulatory Accounts	150	-	150	2	(15)	(13)	137
Total Regulatory Assets	2,761	1,553	4,314	253	(159)	94	4,408
Regulatory Liabilities							
Future Removal and Site Restoration Costs	120	(16)	104	-	(10)	(10)	94
Rate Smoothing	70	-	70	18	-	18	88
Foreign Exchange Gains and Losses	103	-	103	2	(1)	1	104
Other Regulatory Accounts	2	-	2	7	-	7	9
Total Regulatory Liabilities	295	(16)	279	27	(11)	16	295
Net Regulatory Asset	$ 2,466	$ 1,569	$ 4,035	$ 226	$ (148)	$ 78	$ 4,113

OTHER REGULATORY ACCOUNTS

Other regulatory asset accounts with individual balances less than $65 million include the following: Arrow Water Systems Divestiture, Capital Project Investigation Costs, Home Purchase Option Program, Return on Equity (ROE) Adjustment, and Waneta Rate Smoothing.

NOTE 10: LONG-TERM DEBT AND DEBT MANAGEMENT

The Company's long-term debt comprises bonds and debentures and revolving borrowings obtained under an agreement with the Province.

In the three month period ended September 30, 2012, the Company issued bonds with a par value of $355 million (2011- $50 million), a weighted average effective interest rate of 3.13 per cent (2011 – 3.77 per cent) and a weighted average term to maturity of 24 years (2011 – 37 years). For the six month period ended September 30, 2012, the Company issued bonds with a par value of $933 million (2011 - $1.1 billion), a weighted average effective interest rate of 3.31 per cent (2011 – 4.39 per cent) and a weighted average term to maturity of 25 years (2011 – 31 years). Debt issue costs associated with the transactions were $2 million (2011 - $7 million).

NOTE 11: CAPITAL MANAGEMENT

Orders in Council from the Province establish the basis for determining the Company's equity for regulatory purposes, as well as the annual Payment to the Province. Capital requirements are consequently managed through the retention of equity subsequent to the Payment to the Province and a limit on the Payment to the Province if it would cause the debt to equity ratio to exceed 80:20.

The Company monitors its capital structure on the basis of its debt to equity ratio. For this purpose, the applicable Order in Council defines debt as revolving borrowings and interest-bearing borrowings less investments held in sinking funds and cash and cash equivalents. Equity comprises retained earnings, accumulated other comprehensive income (loss) and contributed surplus.

During the period, there were no changes in this approach to capital management.

The debt to equity ratio at September 30, 2012 and March 31, 2012 was as follows:

(in millions)	*As at September 30* 2012	*As at March 31* 2012
Total debt, net of sinking funds	$ 13,740	$ 12,845
Less: Cash and cash equivalents	(178)	(12)
Net Debt	$ 13,562	$ 12,833
Retained earnings	$ 3,203	$ 3,075
Contributed surplus	60	60
Accumulated other comprehensive income	77	84
Total Equity	$ 3,340	$ 3,219
Net Debt to Equity Ratio	80:20	80:20

PAYMENT TO THE PROVINCE

The Company is required to make an annual Payment to the Province (the Payment) on or before June 30 of each year. The Payment is equal to 85 per cent of the Company's net income for the most recently completed fiscal year unless the debt to equity ratio, as defined by the Province, after deducting the Payment, is greater than 80:20. If the Payment would result in a debt to equity ratio exceeding 80:20, then the Payment is the greatest amount that can be paid without causing the debt to equity ratio to exceed 80:20. No Payment has been accrued as at September 30, 2012 (March 31, 2012 - $230 million, included in accounts payable and accrued liabilities), as the Company's debt to equity ratio is at the 80:20 cap prior to the calculation of the Payment.

NOTE 12: POST EMPLOYMENT BENEFITS

The expense recognized in the statement of comprehensive income for the Company's benefit plans for the three and six months ended September 30, 2012 was $23 million and $46 million (2011 - $19 million and $42 million, respectively).

Contributions to the funded defined benefit plan for the three and six months ended September 30, 2012 were $12 million and $24 million, respectively (2011 - $13 million and $25 million).

NOTE 13: OTHER LONG-TERM LIABILITIES

(in millions)	*September 30* 2012	*March 31* 2012
Provisions		
Environmental liabilities	$ 323	$ 301
Asset retirement obligations	93	94
Other	38	3
Total Provisions	454	398
First Nations liabilities	393	393
Finance lease obligations	300	309
Deferred revenue	409	418
	1,556	1,518
Less: Current portion, included in accounts payable and accrued liabilities	(96)	(97)
Total	$ 1,460	$ 1,421

NOTE 14: COMMITMENTS AND CONTINGENCIES

LEGAL PROCEEDINGS

Since 2000, Powerex has been named, along with other energy providers, in lawsuits and U.S. federal regulatory proceedings which seek damages and/or contract rescissions based on allegations that, during part of 2000 and 2001, the California wholesale electricity markets were unlawfully manipulated and energy prices were not just and reasonable. At September 30, 2012, Powerex was owed US $265 million (CDN $261 million) plus interest by the California Power Exchange and the California Independent System Operator related to Powerex's trade activities in California during the period covered by the lawsuits. The Federal Energy Regulatory Commission (FERC) has concluded that because of a dysfunctional energy market in California between October 2000 and June 2001, certain market-wide refunds will have to be paid by energy providers, including Powerex, to various California parties. It is expected that the receivables owed to Powerex will be offset against the market-wide refund amount that Powerex is required to pay.

The Company has elected not to report information regarding provisions as this information could prejudice the Company's position in ongoing litigation.

NOTE 15: SEASONALITY OF OPERATING RESULTS

Due to the seasonal nature of the Company's operations, the condensed consolidated interim statement of comprehensive income is not indicative of operations on an annual basis. Seasonal impacts of weather, including its impact on water inflows, energy consumption within the region and market prices of energy, can have a significant impact on the Company's operating results.

NOTE 16: EXPLANATION OF TRANSITION TO THE PRESCRIBED STANDARDS

In preparing its opening statement of financial position, BC Hydro has adjusted amounts reported previously in financial statements prepared in accordance with CGAAP. An explanation of how the transition from CGAAP to the Prescribed Standards has affected BC Hydro's financial position, financial performance and cash flows is set out in the following tables and the notes that accompany the tables:

Reconciliation of the Consolidated Statement of Financial Position Prepared According to the Prescribed Standards

		September 30, 2011		
(in millions)	Note	Canadian GAAP	Effect of Transition	Prescribed Standards
ASSETS				
Current Assets				
Cash and cash equivalents		$ 5	$ -	$ 5
Accounts receivable and accrued revenue		489	-	489
Inventories		167	-	167
Prepaid expenses		217	-	217
Current portion of derivative financial instrument assets	n	161	1	162
		1,039	1	1,040
Non-Current Assets				
Property, plant and equipment	a-e,g,o	15,754	(299)	15,455
Intangible assets		362	-	362
Regulatory assets	t	2,446	1,133	3,579
Investments held in sinking funds		106	-	106
Employee future benefits	h	284	(284)	-
Derivative financial instrument assets	n	42	1	43
		18,994	551	19,545
		$ 20,033	$ 552	$ 20,585
LIABILITIES AND EQUITY				
Current Liabilities				
Accounts payable and accrued liabilities	n,o	$ 1,079	$ 16	$ 1,095
Current portion of long-term debt	j	2,688	10	2,698
Current portion of derivative financial instrument liabilities	n	115	-	115
		3,882	26	3,908
Non-Current Liabilities				
Long-term debt	j,l	9,971	43	10,014
Regulatory liabilities	t	285	(1)	284
Derivative financial instrument liabilities		162	-	162
Contributions in aid	c	1,071	(2)	1,069
Post employment benefits	h	358	495	853
Other long-term liabilities	f-g,o,r	1,281	(52)	1,229
		13,128	483	13,611
Shareholder's Equity				
Contributed surplus		60	-	60
Retained earnings	b-h,j-o,r	2,902	-	2,902
Accumulated other comprehensive income	k,m,r	61	43	104
		3,023	43	3,066
		$ 20,033	$ 552	$ 20,585

For presentation purposes, the current portion of other long-term liabilities has been reclassified and included in accounts payable and accrued liabilities in the comparative periods under CGAAP, increasing accounts payable and accrued liabilities and decreasing other long-term liabilities by $71 million at September 30, 2011.

Reconciliation of Consolidated Statement of Comprehensive Income

		For the three months ended September 30, 2011			*For the six months ended September 30, 2011*		
(in millions)	Note	Canadian GAAP	Effect of Transition	Prescribed Standards	Canadian GAAP	Effect of Transition	Prescribed Standards
Revenues							
Domestic	c,n,p	$ 748	$ 10	$ 758	$ 1,634	$ 20	$ 1,654
Trade	t	404	40	444	599	46	645
		1,152	50	1,202	2,233	66	2,299
Expenses							
Operating expenses (Note 4)	b-d,f-i,o-q	963	46	1,009	1,829	59	1,888
Finance charges (Note 5)	e,f,i-m,o,q	126	4	130	249	7	256
Net Income		$ 63	$ -	$ 63	$ 155	$ -	$ 155
Other Comprehensive Income (Loss):							
Effective portion of changes in fair value on derivatives designated as cash flow hedges	k,m	$ 64	$ (26)	$ 38	$ 53	$ (26)	$ 27
Reclassification to income of gain (loss) on derivatives designated as cash flow hedges	m	(73)	30	(43)	(65)	30	(35)
Foreign currency translation gains (losses)	r	-	41	41	-	38	38
Other Comprehensive Income (Loss)		$ (9)	$ 45	$ 36	$ (12)	$ 42	$ 30
Total Comprehensive Income		$ 54	$ 45	$ 99	$ 143	$ 42	$ 185

NOTES TO THE RECONCILIATION OF THE CONSOLIDATED STATEMENT OF FINANCIAL POSITION AND CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME PREPARED ACCORDING TO THE PRESCRIBED STANDARDS:

The following explanations disclose the key impacts arising on transition from CGAAP to the Prescribed Standards. The net transitional impacts to retained earnings, contributed surplus and actuarial losses in accumulated other comprehensive income as at April 1, 2011 and for the three and six months ended September 30, 2011 have been deferred to regulatory assets and liabilities on the statement of financial position for regulatory accounting purposes. As identified in BC Hydro's Amended fiscal 2012-2014 Revenue Requirements Application (Amended RRA), BC Hydro will request approval to defer IFRS retained earnings impacts that are not within the current scope of existing regulatory deferral accounts. Refer to Regulatory Note 9 for further information on regulatory accounts.

(a) Fair Value as Deemed Cost

With the application of the deemed cost exemption, the net book value of property, plant and equipment and intangible assets for BC Hydro entities subject to rate regulation at April 1, 2011 have become the opening cost of property, plant and equipment and intangible assets under the Prescribed Standards except for finance leases and asset retirement obligation assets.

(b) Componentization

CGAAP permits component accounting for property, plant and equipment but does not require componentization of assets. IFRS requires the componentization of significant parts of an asset where the useful life or the depreciation method of the part of the asset differs from the remainder of the asset. In addition certain expenditures under CGAAP are eligible for capitalization and are considered asset components under IFRS. The impact of componentization under IFRS as at and for the three and six months ended September 30, 2011 was a decrease in property, plant and equipment of $2 million and $4 million, respectively and a corresponding increase in depreciation expense of $2 million and $4 million, respectively due to the reduction in the useful life of the component assets compared to the life of the parent asset.

(c) Mass Asset Retirements

Under CGAAP, the Company did not record any gains or losses for assets that are tracked on a pooled basis except when entire pools or a substantial portion of an asset pool is retired prior to being fully amortized. IFRS requires that gains and losses on disposal of assets be recognized immediately in income, and not charged or credited to accumulated amortization. The impact of the IFRS requirement for the three and six months ended September 30, 2011 were losses of $7 million and $14 million recognized for the retirement of pooled assets offset by recognition of associated deferred contributions in aid into revenue in the amount $1 million and $2 million, respectively.

(d) Capital Overhead

Under CGAAP, there are expenditures allocated to capital that are associated with capital programs that are no longer eligible for capitalization under IFRS as they are not considered directly attributable to the construction of the asset. The effect of this difference as at and for the three and six months ended September 30, 2011 was a decrease in property, plant and equipment and a corresponding increase in operating costs in the amount of $51 million and $103 million, respectively.

(e) Interest During Construction

Under CGAAP, the Company capitalized interest on all capital projects regardless of project duration period. Under IFRS, interest costs are only capitalized in relation to an asset that takes a "substantial period of time" to prepare for their intended use. The Company considers a substantial period of time to be in excess of six months; therefore interest costs that relate to capital projects with less than six months duration to prepare for their intended use are no longer eligible for capitalization and must be expensed in the period incurred. The effect as at and for the three and six months ended September 30, 2011 was a decrease in property, plant and equipment and a corresponding increase in finance charges of $2 million and $3 million, respectively.

(f) New Provisions

Measurement requirements for provisions under IFRS have a lower recognition threshold than CGAAP and as a result, upon transition to the Prescribed Standards, an ARO has been estimated in connection with asbestos at various locations. This resulted in an increase in total provisions of $26 million and a corresponding decrease in retained earnings as at April 1, 2011. The accretion adjustment for the three and six months ended September 30, 2011 was an increase of less than $1 million in finance charges and a corresponding increase to the environmental liability.

(g) Provision Re-Measurement

Under CGAAP, there was no requirement to re-measure provisions for changes in discount rates. Under IAS 37, *Provisions, Contingent Liabilities and Contingent Assets*, provisions are reviewed at the end of each reporting period and adjusted to reflect the current best estimate, including a reassessment in discount rates where the present value of a provision has been calculated. Upon transition to the Prescribed Standards, the revaluation of these provisions to reflect the appropriate discount rates at the end of each reporting period resulted in an increase in total provisions of $26 million and a corresponding decrease in retained earnings as at April 1, 2011. There was an increase in provisions and provision expense for the three and six months ended September 30, 2011 of $12 million and $19 million, respectively.

The Company elected to use an exemption allowing ARO related assets to be re-measured on a simplified approach at the transition date rather than perform full detailed ARO calculations. At the transition date, the re-measurement increased ARO liabilities by $6 million, increased property, plant and equipment by $4 million and decreased retained earnings by $2 million. In addition to the transition date adjustment, the re-measurement increased the ARO liabilities and property, plant and equipment by $8 million and $10 million for the three and six months ended September 30, 2011, respectively.

(h) Actuarial Gains and Losses Recognition

Under CGAAP, the Company recognized actuarial gains and losses in net income over the employees' remaining service period. Under IFRS, the Company's policy is to recognize all actuarial gains and losses in other comprehensive income. As permitted by IFRS 1, the Company has elected to recognize all previously unrecognized actuarial gains and losses that existed at the date of transition in opening retained earnings for all of its employee post-employment and defined benefit plans. Under CGAAP, the Company recognized past service costs over the expected average remaining service life of the employees. IAS 39 requires all vested past service costs to be recognized immediately. On the date of transition, the Company recognized all vested past service costs into opening retained earnings with a resulting decrease in the post retirement benefit liability.

The effect as at the date of the transition resulted in a decrease to the defined benefit asset of $296 million, an increase in the defined benefit obligation of $500 million and a decrease in opening retained earnings of $796 million. The reversal of amortization previously recognized under CGAAP resulted in a decrease of $9 million and $18 million to the pension benefit obligation and expense for three and six months ended September 30, 2011, respectively.

In accordance with the Prescribed Standards, the impact at transition net of the 2012 reversal of amortization previously recognized under CGAAP has been deferred to the IFRS Pension & Other Post Employment Benefits regulatory account.

(i) Interest Reclassification

Under IFRS, interest on defined benefit obligations and interest on defined benefit plan assets are classified as finance charges rather than as operating costs under CGAAP. The effect was a reclassification of net interest expense on the plan obligations and assets from operating costs to finance charges of $3 million and $6 million for the three and six months ended September 30, 2011, respectively.

(j) Designation of Previously Recognized Financial Instruments

As permitted by IFRS 1, the Company has elected to designate a number of previously recognized financial liabilities as a financial liability at fair value through the profit or loss at the date of transition. The Company has discontinued fair value hedge accounting with respect to a number of its Canadian denominated debt issues and has applied this exemption to the underlying debt under the discontinued hedging relationship. This increased the current portion of long term debt by $10 million, increased long term debt by $53 million and decreased opening retained earnings by $63 million as at April 1, 2011. There was an additional decrease in long-term debt of $8 million and $14 million and a corresponding decrease in finance charges for the three and six months ended September 30, 2011, respectively.

(k) Ineffectiveness On Cash Flow Hedges

Certain methods to assess hedge effectiveness under CGAAP are no longer permitted under IFRS. The resulting transitional adjustment recorded to reflect the hedge ineffectiveness that would have been realized under IFRS in prior years as at the date of transition and the three and six months ended September 30, 2011 was less than $1 million.

(l) Fair Value of Debt Issuance

Certain previous Canadian debt issues were issued to the Province of BC at yields that were higher or lower than market yields (off market rates). This was allowed under CGAAP under the related parties guidance. IFRS requires all debt to be recorded at its fair value at inception. This adjustment is required to reflect the accounting standards under IFRS for off market debt issues. This transitional adjustment results in an increase to debt of $5 million, an increase to contributed surplus of $11 million, and a decrease to retained earnings of $16 million as at April 1, 2011.The amortization of this transitional adjustment for the three and six months ended September 30, 2011 resulted in a decrease to finance charges and long-term debt of $1 million.

(m) De-Designation of Cash Flow Hedging Relationship as at April 1, 2011

This transitional adjustment reverses the mark-to-market adjustment from other comprehensive income to finance charges for the comparative period due to the de-designation of specific hedges. The effect is an increase in other comprehensive income and finance charges for the three and six months ended September 30, 2011 of $3 million and $4 million, respectively.

There was an additional adjustment recorded for the amortization of accumulated other comprehensive income amounts due to the de-designation of hedge accounting on April 1, 2011 for IFRS transition. The transitional adjustment resulted in an increase in finance charges and accumulated other comprehensive income for the three and six months ended September 30, 2011 of less than $1 million and $1 million, respectively.

(n) New Derivatives

Under IFRS, the lack of a specified notional quantity does not preclude a contract from meeting the criteria for classification as a derivative financial instrument, as is the case under CGAAP. As a result, on transition to the Prescribed Standards, a number of transactions previously recognized by the Company as an executor contract under CGAAP are now recognized on a fair value basis under IFRS. The impact on the date of transition was a decrease of $3 million to retained earnings offset by an increase for both derivative financial instrument assets and liabilities of $1 million and $6 million, respectively and a decrease in accounts payable and accrued liabilities of $2 million.

There was a further decrease in derivative financial instruments of $1 million and an increase in accounts payable and other accrued liabilities, offset by a reduction in revenue of $4 million for the three months ended September 30, 2012. There was an increase in accounts payable and accrued liabilities of $3 million and a decrease of $5 million in derivative financial instrument liabilities, offset by an increase in revenue of $2 million for the six months ended September 30, 2011.

(o) Leases

On the date of transition to the Prescribed Standards, an energy purchase agreement was assessed as containing an embedded lease under IFRIC 4. The arrangement was subsequently assessed under IAS 17, *Leases* and was classified as a finance lease. Adjustments were also made to two energy purchase agreements that were classified as finance leases under CGAAP. One agreement was reclassified from a finance lease to an operating lease under IFRS. Another agreement was re-measured using the interest rate implicit in the agreement.

The following table summarizes the impact of the adjustments:

	Incremental Increase (Decrease)		
(in millions)	As at April 1, 2011	For the three months ended September 30, 2011	For the six months ended September 30, 2011
Property, plant and equipment	$ (196)	$ 3	$ 6
Lease obligation liability	(137)	2	4
Accounts payable and accrued liabilities	-	3	9
Retained earnings	(59)	-	-
Finance charges	-	1	2
Operating costs	-	1	5

(p) Contributions in Aid of Construction (CIA)

Under IFRS, contributions that are received by the Company to fund customer connections to the ongoing supply of electricity will continue to be recorded as deferred revenue as in the case under CGAAP. Under IFRS, amortization of the deferred revenue will be recorded as revenue, rather than as depreciation expense under CGAAP. The effect for the three and six months ended September 30, 2011 was a reclassification from depreciation expense to revenue of $10 million and $20 million, respectively.

(q) Accretion expense reclassification

Under IFRS, accretion expense is classified as finance charges rather than as operating costs under CGAAP. The reclassification adjustment from operating costs to finance charges was less than $1 million and $1 million for the three and six months ended September 30, 2011, respectively.

(r) Functional Currency

In accordance with IFRS 1, the Company elected to deem all foreign currency translation differences arising on consolidation of Powerex to be nil at the date of transition, April 1, 2011. The foreign currency translation adjustment was a gain of $41 and $38 million recognized in other comprehensive income for the three and six months ended September 30, 2011, respectively. The impact of foreign currency translation on consolidation is not deferred for regulatory purposes.

In addition, as a result of the change in Powerex's functional currency, Powerex recorded adjustments to its foreign exchange gains and losses as at April 1, 2011 and for the three and six months ended September 30, 2011. The impact of these adjustments was to decrease retained earnings by $3 million at April 1, 2011 and to record a foreign exchange loss of $35 million and $32 million for the three and six months ended September 30, 2011, respectively. The impact of these differences has been deferred for regulatory purposes in the Trade Income Deferral Account.

(s) Change in Classification of Cash Flows

The following table is a reconciliation of the change in classification of cash flows arising from the transition to IFRS for the six months ended September 30, 2011:

(in millions)	Canadian GAAP	Effect of Transition to IFRS	IFRS
Net cash used in operating activities	$ 306	$ 49	$ 355
Net cash provided by financing activities	465	-	465
Net cash provided by investing activities	(793)	(49)	(842)

The adjustments to the cash flow classification arise as a result of the presentation of the Company's CIA amortization and an adjustment to remove capitalized interest from property, plant and equipment expenditures, which were reclassified from investing activities to operating activities.

(i) Deferral of IFRS Transitional Impacts

The IFRS transitional impacts to retained earnings, contributed surplus and actuarial losses in accumulated other comprehensive income have been deferred for regulatory purposes. The changes have increased (decreased) regulatory assets and liabilities as follows:

(in millions)		Incremental Increase (Decrease)	
	Note	For the six months ended September 30, 2011	
Componentization	b	$	4
Mass Asset Retirements	c		12
Capital Overhead	d		103
Interest During Construction	e		3
New Provisions	f		1
Provision Re-Measurement	g		19
Actuarial Gains and Losses Recognition	h		(18)
Designation of Previously Recognized Financial Instruments	j		(14)
Ineffectiveness of Cash Flow Hedges	k		(1)
Fair Value of Debt Issuance	l		(1)
De-Designation of Cash Flow Hedging Relationship	m		5
New Derivatives	n		(2)
Leases	o		7
Foreign Exchange	r		32
Incremental increase for the period	w		150
Cumulative increase as at the balance date		$	1,134
Regulatory assets		$	1,133
Regulatory liabilities			(1)
Net regulatory increase		$	1,134

The regulatory transfer of the IFRS impacts on trade income resulted in a reclassification of $40 million and $46 million from trade revenue to operating costs for the three and six months ended September 30, 2011, respectively.